A barrier and techno-economic analysis of small-scale biomass combined heat and power (bCHP) schemes in the UK

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Abstract:
Biomass combined heat and power (bCHP) systems are highly efficient at smaller-scales when a significant proportion of the heat produced can be effectively utilised for hot water, space heating or industrial heating purposes. However, there are many barriers to project development and this has greatly inhibited deployment in the UK. Project viability is highly subjective to changes in policy, regulation, the finance market and the low cost fossil fuel incumbent. The paper reviews the barriers to small-scale bCHP project development in the UK along with a case study of a failed 1.5 MWel bCHP scheme. The paper offers possible explanations for the project's failure and suggests adaptations to improve the project resilience. Analysis of the project's: capital structuring; contract length and bankability; feedstock type and price uncertainty, and; plant oversizing highlight the negative impact of the existing project barriers on project development. The research paper concludes with a discussion on the effects of these barriers on the case study project and this industry more generally. A greater understanding of the techno-economic effects of some barriers for small-scale bCHP schemes is demonstrated within this paper, along with some methods for improving the attractiveness and resilience of projects of this kind.

Keywords: biomass CHP case study; project barriers; project development; techno-economic analysis; levelised energy cost (LEC)

Nomenclature:
°C – Degrees Celsius
c. – Circa
bCHP – Biomass CHP
CAPEX – Capital expenditure
CHP – Combined heat and power
d – Day
DHN – District heating network
DNO – District Network Operator
DSC – Debt service cover
DSCR – Debt service cover ratio
EBIT(DA) – Earnings before interest, tax (depreciation and amortisation)
EfW – Energy from waste
EPC – Engineering, procurement and construction
GJ – Gigajoule
kWel – Kilowatt electrical
kWhel – Kilowatt hour electrical
kWhth – Kilowatt hour thermal
kWth – Kilowatt thermal
LEC – Levelised energy cost
Levy EC – Levy Exemption Certificate
MWel – Megawatt electrical
MWhel – Megawatt hour electrical
MWhth – Megawatt hour thermal
MWth – Megawatt thermal
NPV – Net present value
ODT – Oven dry tonne
OPEX – Operating expenditure
ORC – Organic rankine cycle
PPA – Power Purchasing Agreement
RHI – Renewable Heat Incentive
RO – Renewables Obligation
ROC – Renewable Obligation Certificates
ROE – Return on equity
SME – small, medium sized enterprise
UK – United Kingdom
yr – Year

P_e – Electricity price (£/MWhel)
$O\&M_t$ – Operations and management cost (£/yr)
F_t – Fuel cost (£/yr)
H_t – Heat revenue (£/MWhth)
R_t – Incentive revenue (£/yr)
E_t – Electricity production (MWhel/yr)
$(1+r)^{-t}$ – Discount factor, r is the rate of discount (%).
a_t – Annuity (£/yr)
$DSCR_t^T$ – Debt service cover ratio target

1. Introduction

Biomass is projected to account for approximately half of the new energy production needed to meet the 15% primary energy generation target by 2020 in the UK [1][1]. Yet current progress has been much slower than required, especially in the case of renewable heat. Project viability is highly subjective to policy and regulation [2], and meeting finance terms [3]. Combined heat and power (CHP) is the most efficient method of biomass combustion, yet UK capacity only grew by 1% between 2010 and 2011 [4]. Moreover, the ad hoc approach of many private developers pursuing their motives has led to a high number of projects failing principally at the development phase of the project lifecycle [5]. This has created an opportunity for the research to contribute by formalising and supporting the process of decision-making in the early stages of project development.

Bioenergy is a predictable and non-intermittent technology [1], not suffering from the supply issues of wind and solar technologies, although it is dependent on securing a continuous and suitable feedstock to maintain operation which usually incurs a cost not present in the aforementioned technologies. By better utilising the domestic biomass resource to produce energy, it is believed that there will be direct and indirect socio-economic and environmental benefits to the UK [6]. There are multiple bioenergy technologies for providing heat and power but combustion is the most established commercially available thermal conversion technology [7]. CHP is defined as "… the simultaneous generation of usable heat and power (usually electricity) in a single process" [4]. CHP, also known as cogeneration, differs from the typical UK approach to power generation as it captures the heat by-product from electricity production and utilises it for heating purposes. The most common applications for heat are for hot water, space heating or industrial heating purposes.

1.1 *Combined heat and power (CHP) schemes in the UK*

By the end of 2011 there were 1,880 operational CHP schemes in the UK, ranging from micro-scales of < 100 kWel to large scale of > 10 MWel, with the largest being 316 MWel. The operational schemes are predominantly fuelled by natural gas (70%) [4].

Table 1 – CHP schemes by capacity size ranges 2011 [4]

Electrical capacity	No. of schemes	Share of total (%)	Total capacity (MWel)	Share of total (%)
< 100 kWel	535	28.5%	33	0.5%
100 kWel – 999 kWel	1,024	54.5%	250	4.1%
1 MWel – 9.9 MWel	252	13.4%	828	13.6%
> 10 MWel	69	3.7%	5000	81.8%
Total	**1880**	**100%**	**6111**	**100%**

Table 1 highlights the breadth of schemes operational and the market for CHP in the UK. The scope of this paper is limited to schemes ranging from 500 kWel to 10 MWel as at the lower end this is the minimum technical size for steam turbines [8, 9] and at the upper end there are decreasing possibilities to fully utilise the heat output. Schemes listed in the Ofgem (Office of the Gas and Electricity Markets) register over 1 MWel, have a total installed capacity of 2,193 MWel of which 1,233 MWel is classed as 'good quality' CHP [4], meaning that heat utilisation is an issue for the operational schemes even at this relatively small scale.

The extent to which CHP, and most energy generating facilities renewable or otherwise, are built depends on two major factors: spark or bark spread economics and the payback term of schemes [4].

[1] Technology breakdown (terawatt hours) for central view of deployment in 2010 (excl. renewable transport)

The spark or bark spread economics are essentially the gross margin between the wholesale electricity price and the cost of gas or biomass respectively [10], usually expressed in £/MWh. Studies have shown that gas CHP schemes are very sensitive to changes in the gas and electricity prices, which may happen asynchronously [11, 12]. However, biomass schemes face an additional economic challenge as their economic viability is also subject to changes in the feedstock market and in relation to the fluctuating price of gas and electricity. Long term deployment of bCHP schemes, especially over the low cost gas incumbent, will only happen when the bark spread is greater than the spark spread. This may occur naturally with rising gas prices or, more likely in the shorter term, increasing Government policy and support for bCHP under incentives such as the Renewable Heat Incentive (RHI). The minimum levelised unit cost (per MWh) to make a project viable is a more detailed indicator of the gross margin and suitability of an energy project. It is also widely used in industry by a range of decision-makers and therefore is applied within this paper as opposed to the spread measure. The levelised energy cost measure is covered in detail in Section 2.1.

CHP is best suited to small-scale decentralised applications as it important to size for the heat and power loads of a specific site [13]. At the upper end of the defined range, a district heating network (DHN) will be required to utilise a significant proportion of the produced heat in order to be viable and maximise production incentive benefits for 'good quality' CHP. Heating networks currently supply less than 2% of the UK's heat demand [Ibid cited 14] and predominantly heat social housing, tower blocks and public buildings with fossil fuel CHP due to more favourable economics [14]. However, smaller scale schemes have been found to be less profitable than larger schemes [13]. It is also difficult to evaluate the investment opportunity of bCHP schemes due to high costs, high complexity and multiple sources of risk [15].

1.2 *Failed bCHP schemes*

Roves Energy were awarded a UK Government Bioenergy Capital Grants Scheme grant of £960,000 in 2003 to build a 2 MWel bCHP scheme in the Swindon area that was subsequently withdrawn in 2008 due to lack of progress [16]. Corpach CHP, a partnership between ArjoWiggins paper mill and EPR (Energy Power Resources) Ltd., were similarly awarded a £5m grant under the same scheme in 2003 to build a 5 MWel bCHP [17] yet the mill was closed in late 2005 [18]. Some schemes were more successful, such as Eccleshall biomass. Earlier research [19] recorded this development as a 2.2 MWel CHP in development though it is now an operational 2.6 MWel power only scheme [20]. More recently there has been a failed DHN bCHP scheme in Wick. The non-profit scheme started in 2004 with a proposed a 1.5 MWel/ 3 MWth CHP installation for the community that would have significantly reduced the residents' utility bills [21]. In 2011, the scheme was finally wound up with a total cost estimated of £14m in public subsidies without providing any low carbon energy and having to pay for re-converting properties to run on fossil fuelled systems again [22, 23]. Several other failed bioenergy projects have failed due to various barriers [24-26].

2. Method

2.1 *Levelised electricity cost calculation*

Levelised energy costs (LEC) are frequently utilised by decision-makers within the energy industry to assess the viability of potential renewable energy projects and inform policy. The measures' simplicity and usefulness means that they are frequently applied to a wide range of low carbon or traditional fossil fuel generation technologies. The Department of Energy and Climate Change (DECC), the International Energy Agency (IEA), and the National Renewable Energy Laboratory (NREL) frequently apply the LEC as a viability measure. In the UK, policy decisions are also often informed by levelised unit costs [27]. LEC are also widely utilised as a measure in academic research [28, 29].

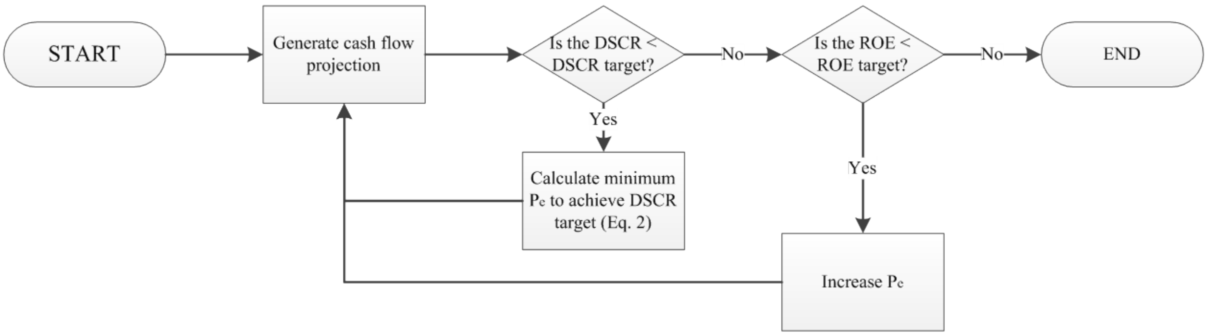
The method applied is the discounting method as it is the most commonly utilised [30, 31]. The discounting method is the total present value of the costs divided by the total present value of electricity produced over the project's lifetime. This gives the minimum unit cost of electricity (MWhel) for the project to break-even. Equation 1 has been adapted to include the benefit of revenue from heat sales that benefit CHP systems and the associated incentives.

$$LEC = P_e = \frac{\sum_t ((O\&M_t + F_t - H_t - R_t)(1+r)^{-t})}{\sum_t (E_t(1+r)^{-t})} \tag{1}$$

Where: P_e is the levelised minimum electricity price (£/MWhel); $O\&M_t$ is the operations and management cost in year t (£/yr); F_t is the fuel cost in year t (£/yr); H_t is heat sales revenue in year t (£/MWhth); R_t is the incentive revenue in year t (£/yr); E_t is the electricity production in year t (MWhel/yr); $(1+r)^{-t}$ is the discount factor for year t, and; r is the rate of discount (%).

Discounting future costs ($O\&M_t, F_t$) and revenues (H_t, R_t) to present values within the equation along with future electricity production (E_t) produces the minimum levelised electricity price P_e required for a project to break-even. An increase or decrease in electricity value P_e beyond this break-even value would produce a gross profit or loss for the plant respectively. This calculation does not include the cost and terms of project financing that are required to give a more detailed analysis of the economic viability of a project.

To calculate the minimum break-even LEC that incorporates the financial covenants of project finance, the paper utilises the algorithm given in Figure 1 and the supporting equation (Eq. 2) demonstrated in earlier research [32].



Where DSCR is the debt service cover ratio and ROE is the return on equity remunerated from the free cash flow

Figure 1 – Minimum LEC for project finance algorithm flow chart [32]

Figure 1 assumes that the return on equity is remunerated to the equity investors from the free cash flow. The algorithm sets an initial electricity price P_e and simply calculates a typical project cash flow (as shown later in Table 8). If the debt service cover ratio (DSCR) does not meet the target condition then a new rate of P_e is calculated (Eq. 2). Secondly, the return on equity (ROE) is calculated from the project cash flow to meet that required by equity investors. If the ROE does not meet the required project hurdle rate then the price is increased in increments until achieved. The final value of P_e is the project's LEC that incorporates the financial covenants.

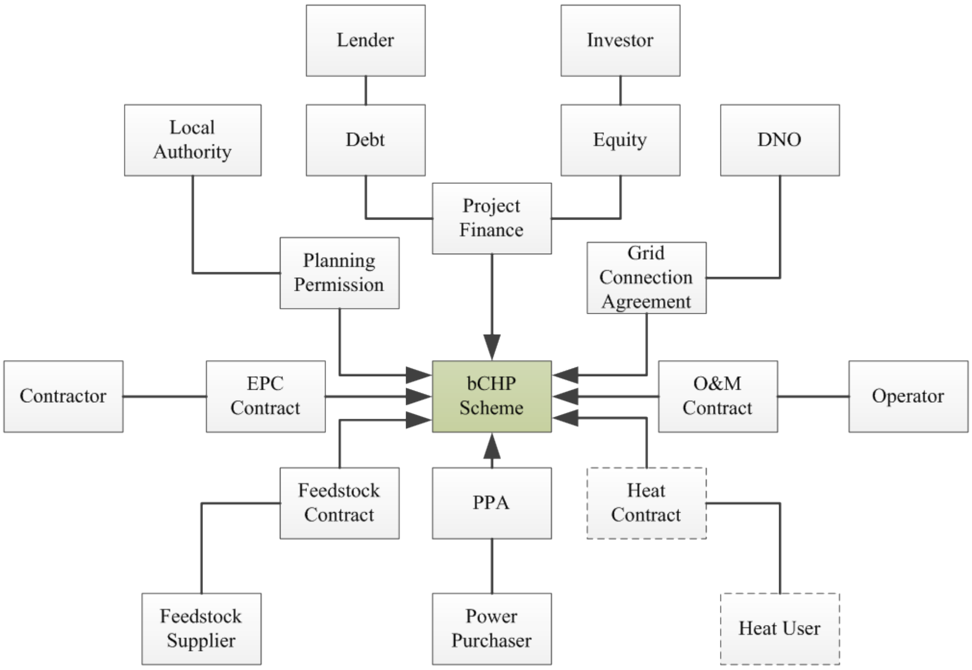
$$P_e = (a_t \cdot DSCR_t^T) - ({}^{\alpha}O\&M_t + F_t - H_t - R_t))/E_t \tag{2}$$

Where: a_t is the annuity in year t and $DSCR_t^T$ is the DSCR target in year t.

It is often the case in project finance that as a project does not make a positive return in the free cash flow for several years from commissioning that equity is returned from an additional subordinated debt cash flow before tax. This is not considered in the current algorithm but would improve the LEC for a given project.

3. Project stakeholders and contracts

To successfully develop a project it is necessary to have contracts or agreements with several key stakeholders [33, 34]. Although there may be some different stakeholders and contracts required [35] depending on the type and size of the project, the problem is essentially similar, as shown in Figure 2.



Where EPC is engineering, procurement and construction; PPA is a power purchasing Agreement; DNO is the district network operator

Figure 2 – bCHP scheme stakeholders and contracts (adapted from Yescombe [34]*)*

The simplified figure highlights the key stakeholders required for project financing a bCHP scheme. The strength of the contractual arrangements between the parties is particularly crucial in securing project financing [36]. In some instances, there are multiple stakeholders e.g. heat user(s) or investor(s). Within the figure and covered in greater detail in Section 3.7, the heat user and heat contract are dashed to highlight a critical barrier specific to bCHP schemes. In the following sections, each stakeholder and their relationship to a project is covered in turn, along with the possible issues and barriers identified within the literature. A summary table of all the above mentioned barriers is given in Table 3.

3.1 *Project finance*

Project financing is one of the two main methods for asset financing projects. For project financing, it is necessary to secure debt, equity and credit sources to cover the required capital to proceed with the project. Capital structure, often expressed as a ratio, is the mixture of debt and equity required for financing a project [3]. The loan structure requires on a certain level of project cash flow and asset security [37]. The main types of capital for project finance can be generally categorised as:

- senior debt;

Senior debt constitutes the largest proportion of the capital structure and is not subordinate to any other liability [38]. By being the most senior liability for the project, it is the least costly form of finance.

- subordinate debt (mezzanine finance);

As subordinate debt is unsecured and junior to senior debt, it often requires a higher rate of interest to be paid. In instances where the traditional senior debt and equity portions of the finance do not amount to the total capital required, subordinated debt can allow the project to go ahead, although the company would need to have sufficient cash flow to cover this additional capital cost.

- equity.

Equity is capital invested into the project by an investor or investors who are typically issued with shares and paid in return in dividends. Dividends are normally paid from the 'free cash flow' which is the cash flow after all operating expenses and debt have been serviced [33]. Equity investors are the last in priority of repayment [38] and are far less risk adverse as it is possible to have unbounded returns from the success of an investment [36].

A project's capital structure has a direct effect on the levelised unit cost when finance repayment and necessary covenants are included, as debt tends to be less costly than equity and is therefore generally preferred. The gearing of debt to equity is negotiated between the project sponsor and the lender and is subjected to many factors such as market expectations and project risk [38]. Typically, the lender is the primary enforcer of contracts to reduce risk exposure and will assess the track record or credit-worthiness of each party before choosing whether to lend [35].

3.1.1 *Lender*

Debt is a secured loan typically provided by banks. Lenders are typically risk adverse and wherever possible attempt to reduce unnecessary exposure as there is no financial reward for not doing so (unlike equity investment) [36]. Fabozzi and de Nahlik [38:67] cover the key characteristics a lender desires in a good project and sponsor, such as:

- a professional and thorough feasibility study and financial plan;
- experience and track record in the contractor and operator;
- an assured market for the product [heat and power];
- confidence and continuity in the project manager and the management team;
- confidence and continuity in the operation and financial management of the plant throughout the project;
- confidence that there will be a high level of communication and that all necessary financial information will be given in the correct format and in a timely manner;
- the sponsor needs to have financial substance, be motivated by adequate profits made through dividends, and have had experience with project financing in the past and the potential problems ahead.

Debt finance terms are stipulated in the 'term sheet' issued by the lenders. This term sheet states the debt interest rate, debt term, maximum debt-to-equity ratio and necessary levels of debt service cover. Debt is repaid over the debt term in the form of a debt service payment; this is the principal and interest, usually paid annually. The additional cash flow required over the debt term is to protect the debt service payment if any unforeseen risks should occur or the project performs less well than expected. This is referred to as the debt service cover (DSC) and is calculated as a ratio (DSCR) of the net operating income divided by the debt service payment. The two main types of debt accessible to sponsors are senior and subordinated debt.

3.1.2 *Equity investor*

The equity investor may be the project developer or a third party investor and would want to ensure the project produces the projected return on its investment [35]. Lenders require equity to constitute part of the capital structure of a potential project when project financing. As stated by Fabozzi and de Nahlik [38], equity is deemed by lenders to provide a 'margin of safety' by reducing the effect and size of the debt service on the project cash flow and by increasing the sponsors commitment to the project. The 'threshold' hurdle or minimum rate of return set by equity investors depends on the type of investor (e.g. infrastructure, venture capital, community or not-for profit). Previous research has attempted to deconstruct the various elements of the threshold rate for operational or near operational wind projects (Table 2).

Table 2 – Return on equity components[32]

Component	Dunlop [39]	de Jager and Rathmann [40]	Description
Risk free rate	3%	3 to 5%	Equivalent to 10 year Government bonds
Risk premium	4%	4 to 5%	Similar asset classes to wind power: water funds, comparable shipping deals etc.
Equity fund fees	2%,3%	2%,3%	Fund management fees and illiquidity premium as the stock cannot be sold easily
Technology premium	3 to 5%	3 to 15%	Technology risk premium, Dunlop states that established technologies, such as wind power, may not receive the premium
Regulatory premium	-3 to 3%	-3 to 3%	Regulation risk relating to support schemes and the energy market

3.2 *Developer*

Developers are typically concerned with the implementation and operation of plants [41]. There are different types of developer and they will have their own motivation and objectives from a project. This may influence their approach to project development and to what they consider a successful project. Several barriers have been defined for developers, though the degree to which they impact may differ depending on the developer type. Risk in the development phase [39] and development or operational cost uncertainty [41]. Project scoping viability was also identified by DECC as a significant barrier to the deployment of electricity only dedicated biomass power plants [1]. Furthermore, the DECC report goes on to add that the relatively long development lead time reduces financier confidence in Government policy, to the extent that it may hinder projects. All stakeholders in an industry wide stakeholder analysis for the 2012 UK Bioenergy Strategy stated that they wanted the Government to set clear policy and to be mindful of this issue when making policy decisions [42]. Finally, the development of EfW (energy from waste) combustion plants face additional barriers, namely from the increased level of public opposition [1].

3.3 *Local authority and community*

The Local Authority and community are key stakeholders to potential schemes as they strongly influence whether or not planning permission is granted. Local policy and community opinion has been shown to be a critical success factor for projects [43]. The most common barrier faced by developers with regard to this group is, what is often referred to as, NIMBYism [25, 44]. The 'not in my backyard' opposition of the local community in some instances was actually found to be a concern that the project only served to economically benefit the developer [25]. Rösch and Kaltschmitt [44] developed a list of some of the key concerns of local residents, such as the effect on:

- traffic;
- local employment;
- local and regional environment;
- attractiveness and image of the community.

However, community energy schemes have been shown to have less public opposition and a more positive perception generally [45, 46]. Local developers have also been found to be more trusted than national ones [47].

Planning Permission is considered a significant barrier to dedicated biomass project development in the 2011 UK Renewable Energy Roadmap [1]. Obtaining planning permission has for a significant time been a major barrier for bioenergy project development [Upreti and van der Horst, 2004 cited 5, 25, 47, 48], with research in the onshore wind sector showing the number of permission granted by appeal being alarmingly high, as is the non-reclaimable cost associated with the appeal process [49]. This is also the case more generally, and an issue in the UK Renewable Energy Strategy [5].

3.4 *EPC contractor*

An EPC (Engineering, Procurement and Construction) or 'turn-key' contractor is the major contractor for the engineering, procurement and construction of the plant. EPC contracts are the most prevalent method employed, as financiers have been cautious and tend to 'offset' risk with EPC contracts [1]. The competencies, reliability and experience of the EPC contractor are defined as key success criteria [50]. In the case of the ARBRE gasifier project (2002), the EPC contractor suffered financial problems that not only delayed the plant but eventually contributed to the project failing [51]. A stakeholder for the case study (Section 4) suggested that the EPC contractor margin could be up to 20% of the project cost. Moreover, high construction costs are considered another barrier to market energy for renewable energy technologies [52].

3.5 *Operator*

The operator may be the project developer, one of the project sponsors or a third party chosen to run the scheme [35]. Mott MacDonald [53] states that the operating costs for small-scale CHP are likely to be higher than for power only plants with higher annual fixed costs (per MW) than larger, utility scale plants. [54]. However, this does not create a significant barrier to development and operation.

3.6 *Feedstock supplier*

The feedstock supplier is a key project stakeholder as the largest operational expense is, in most cases, the supply of biomass. Adams, Hammond [41] noted several barriers to greater feedstock supply, with the most significant being competition with other investments, the uncertainty of funding and return on investment. Moreover, a drive toward enforcing sustainable biomass feedstocks under the production incentives [6, 42, 55] is believed may cause potential longer-term issues for the bioenergy sector. Feedstock sustainability and supply of sustainable feedstock are therefore possible barriers to future uptake [1]. The NNFCC [56] also found that certain feedstock markets are inaccessible because of a lack of supply chain infrastructure in the case of waste wood, or uneconomical as the incentive is too low (large scale RHI Tariff) in the case of industrial pellets.

Financiers typically attempt to reduce risk here, in a similar way to the EPC contract, by demanding a long-term feedstock supply contract [1]. In order to secure debt finance it is necessary for the feedstock supply contract length to match the duration of the debt-servicing period. E4tech [57] interviewed several industry professionals and found that long-term contracts can range from 5-15 years with 10 being the average – possibly due to this being the typical debt term. The added security of a long-term contract does however restrict the developer to only use the contracted feedstock and not benefit from any favourable changes in the feedstock market. Hence why co-firing or EfW plants do not wholly contract for their required supply and purchase on the spot market [57].

3.7 *Heat user*

A heat user is defined as a potential purchaser of the heat from the CHP scheme. Acceptable uses, in the context of the RHI, are space and hot water heating, commercial or industrial heating requirement or other economically justified requirements [55]. The Enviros [58] report for BERR on the barriers to renewable heat found significant demand-side uptake barriers for non-domestic applications, these include:

- retrofitting costs;
- consumer confidence and perceived hassle;
- lack of skilled advisory personnel.

If a DHN is required to supply multiple heat users, the installation cost in new and retrofitted applications is a significant supply-side barrier [58], with DECC [14] estimating that the installed cost of district heating pipe may be as high as £1000 per metre. Pöyry [59] attributes this high cost to several factors, including: high cost of laying the pipe; no UK pipe system manufacturing; lack of experience in the technology and overestimated construction risk contingency.

Consumer attitude is also a significant barrier. The NNFCC [56] report to DECC found that there is an unwillingness to sign heat off-take agreements and a belief that the necessary contracts to cover project financing would lead to a monopoly once established. DECC [14] suggests that increasing scale in DHNs may help to increase the attractiveness to investors and allow smaller heat users to connect on potentially shorter term or competitive contracts. Due to the cost of installing a DHN, the payback period could be up to 20 years and therefore it is essential for the developer and potential financiers to have a high degree of confidence that there will be a sufficiently secure heat demand [14]. This is a complex problem to manage as it then becomes necessary to have a robust long-term heat off-take contract with one or multiple credible heat users to secure finance [53, 59]. Furthermore, the problem increases in risk the greater the number of private sector users [59].

3.8 *Power purchaser*

The power purchaser is a licensed supplier of electricity, who most likely has an obligation under the Renewables Obligation (RO), or an aggregator [52], the most dominant being the ‘big six’ licensed electricity suppliers, however there are a total of 75 possible UK suppliers that are required under the RO to purchase a specified quota of electricity from renewable sources [60].

Often generators, that fall outside the Electricity Order 2001 [61], cannot directly supply electricity unless they are a licensed supplier and this has been too complex and costly for small-scale generators to pursue [52, 62]. However, Ofgem and DECC have been working to reduce these barriers and further support small-scale suppliers in distributed energy generation by adjusting the Electricity Act 1989 [63] to better reflect a change in the private market since its inception [62]. Moreover, this helps to reduce the access to market barriers felt by generators [64], although the supply of electricity to consumers is likely to pose the same difficulties as heat sales (Section 3.7), as secure, long-term fixed off-take contracts would still be necessary for acquiring finance.

A power purchasing agreement (PPA) is typically a remuneration contract with an energy supplier or aggregator for electricity production, the associated incentives (such as Renewables Obligation Certificates (ROC) and Levy Exemption Certificates) and other embedded benefits [64]. A more recent call for evidence on long-term contracts indicates that developers feel the PPA market has severely worsened to the point of potential investment hiatus [65]. Due to the importance of the RO in driving the industry, developers and generators are worried that with the incentive being vintaged in 2017, conditions could become increasingly difficult for independent generators as there would no longer be sufficient motivation for suppliers to enter into PPAs to meet a quota [52].

3.9 *District network operator*

The District Network Operator (DNO) is defined as a "…company responsible for the operation and maintenance of a public electricity distribution network" [66]. The recent survey by NNFCC found that the cost and timing of grid connections still remained the most significant barrier for developers [56]. A 2011 Ofgem [67] forum found that several industry stakeholders required greater information on the connection process and greater cost transparency from the DNOs. They also found the different approaches to charges and payment schedules for generators frustrating. The DNO is obligated to offer terms for the connection of the proposed generator as stipulated under the Electricity Act 1989 [63] as a condition of their license [68], although DNOs have been previously accused of not approaching the connection of distributed generators in a "sufficiently positive way" [69].

Table 3 – Summary of small-scale bCHP scheme project development barriers

Developer	Local authority and community	EPC contractor	Feedstock supplier	Heat user	Power purchaser	District network operator	Operator and maintenance
Development phase risk [39]	Local policy and community opinion – success factor [43]	Competencies, reliability and experience of the EPC contractor – success criteria [50]	Supply side – competition with other investments, uncertainty in funding and ROI [41]	Consumer confidence, perceived hassle and contract length [53, 56, 58, 59]	Complexity and cost of distributed generation [52, 62]	Cost and timing of grid connections [56]	Slightly higher costs [53]
Development or operational cost uncertainty [41]	NIMBYism – or genuine concern and motive [25, 44]	High construction costs and contingency margin [52]	Sustainability reporting drives [6, 42, 55]	Lack of skilled advisory personnel [58]	Access to market [64]	Information on the connection process [67]	
Project scoping viability [1][1]	Planning permission [1, 5, 25, 47, 48][2]		Lack of supply chain infrastructure [56]	Retrofitting and DHN cost [58, 59]	PPA market conditions and terms [65]	Cost transparency [67]	
Long lead times [1]			Securing the necessary contract length [57]	Investment payback and attractiveness [14]	End of the RO [52]	Negative approach by the DNO [69]	
Government policy confidence [1]			Not able to utilise the spot market [57]				
Government to set clear policy [42]				Multiple private contract credibility [59]			
EfW public opposition [1]							

[1] Electricity only plants; [2] Upreti and van der Horst, 2004 cited in Upreti and van der Horst, 2004

4. Energy Company case study

The company's name has been changed to maintain confidentiality. Energy Company was a small to medium sized enterprise (SME) which aimed to develop and operate small-scale bCHP schemes in the UK. The company's vision was to implement and operate several small-scale bCHP schemes over a five to 10 year period. They were in the development phase of their first project when the research started and received planning permission after a year, but did not manage to develop the project much further than this or to secure project finance. The company went into administration and dissolution over 2012.

The case study is of this failed small-scale biomass CHP project. If successful, the bCHP plant would have supplied onsite heat and power to residential and light-industrial properties, and exported any additional power to the grid. Although the project received planning permission, it was unable to leave the developmental stage by securing finance also known as 'financially closing' the project. There were several potentially contributing risk factors and challenges over the project's duration of development, such as:

1. capital structuring;
2. contract length and bankability;
3. feedstock type and price uncertainty;
4. plant oversizing.

The data used for the case study was projected by the company or estimated from the characteristics of the site.

Technology

A 1.5 MWel net capacity, virgin wood chip fired bCHP combustion plant with an extraction-condensing turbine was proposed for the site. Table 4 shows the key performance metrics for the chosen CHP technology.

Table 4 – Technology and feedstock characteristics

Technology	**Unit**	**Value**
Net Capacity	MWel	1.5
Heat to power ratio	H:P	3.5:1
Thermal losses (boiler)	%	15
Parasitic load	%	12
Electrical efficiency	%	20
Availability	%	90
Feedstock		
Cost	£/ODT	50
Energy content	MWh/ODT	4.8

The heat to power ratio implies that 3.5 units of heat are produced for every unit of electricity produced. There would have also been losses in the efficiency of the boiler and a parasitic load of electricity, set at 15% and 12% respectively. Plant availability was estimated at 90%, resulting in approximately 7800 operational hours per year.

The virgin woodchip was the bi-product of an industrial wood processing plant. This was not commercial grade wood chip, as this would have a significantly higher cost. The feedstock cost of £50 per oven dry tonne (ODT) was correct at the time of project development; however a more recent price for this feedstock is greater than £70 ODT[2].

Location

The site had a mixture of residential and light-industrial premises. It was possible to gain a grid connection for the site, but it would have been necessary to retrofit a district heating network to provide heat for hot water and space heating purposes.

Table 5 – Residential and industrial demand

Category of user			
Residential[3]	**Unit**	**Potential**	**Achieved[1,2]**
Electricity	kWhel/d	1967	983
Heat	kWhth/d	7597	3799
Non-domestic		**Potential**	**Achieved[4,5]**
Electricity	kWhel/d	6606	686
Heat	kWhth/d	11736	1220

[1] Assumed at 50% of total residential capacity; [2] Total demand divided by 365 days as insufficient information available to calculate weekend demands; [3] Residential electricity demand assumed at 4,174 kWhel/per dwelling/yr and gas demand assumed at 15,698 kWhth/per dwelling/yr [70]; [4] Typical open plan office electricity consumption set at 85 kWhel/m$^{2/yr}$ and heat demand set at 151 kWhth/m^2/yr [71]; [5] Based on the inhabited non-domestic properties

Table 5 shows that if the site was fully occupied the onsite heat and power demand potential for the scheme was high. However, this was not the case and it was expected to take a significant number of years to reach this target. The annual industrial to residential heat demand ratio was approximately 1:3 with the assumption that there was no non-domestic heat and power demand on the weekends. There is also the assumption that the CHP system can always meet the site load. Furthermore, the onsite price of heat and power was to be set competitively with the fossil fuel generated equivalents for domestic electricity at £0.12 kWhel and gas at £0.05 kWhth, and small-scale non-domestic utilities at £0.10 kWhel and gas at £0.03 kWhth

Finance

The project capital expenditure (CAPEX) and operational expenditure (OPEX) were estimated in the actual project and these estimates are given in Table 6. Furthermore, limited recourse project financing was to be pursued as it was not possible to have corporate 'on-balance sheet' financing due to insufficient funds and the sponsor lacking the track record to secure additional funding through the company.

Table 6 – Project costs

Cost group		
CAPEX	**Unit**	**Value**
Development	£000s	100
Plant	£000s	4000
EPC	£000s	500
Other (DHN)	£000s	200
OPEX		
Maintenance	£000s/yr	50
Operations	£000s/yr	200
Insurance	£000s/yr	5
Land Lease	£000s/yr	250
Other	£000s/yr	0

[2] Telephone conversation with a Biomass Procurement Manager (September 2012)

Excluding the biomass feedstock operational costs or running the facility, the land lease of £250k/yr was the largest operating expense. In addition to the various costs for the facility, the project would have been eligible under the UK's primary production incentive, the Renewables Obligation with ROCs and under the Climate Change Levy with Levy Exemption Certificates (Levy ECs), as shown alongside the finance terms in Table 7.

Table 7 – Incentives and finance terms

Incentives[1]			**Finance**		
	Unit	**Value**	**Variable**	**Unit**	**Value**
ROCs	ROC/MWhel	1.5	Debt Term	Yrs	10
ROC Price	£/MWhel	47	Debt Interest	%	6
Levy ECs Price	£/MWhel	4.7	Debt Service Cover Ratio		1.35
			Return on Equity	%	15
			Tax	%	28

[1] Incentive rates correct for late 2010

A dedicated biomass CHP combustion plant running receives 1.5 ROCs/MWhel and the ROC price modelled by Energy Company was £47/MWhel. However, as the ROC is a market based incentive, the price can vary greatly and is currently closer to £43/MWhel [72]. Accredited bCHP plants are also exempt from the Climate Change Levy and receive Levy ECs that had a resale value of c. £4.70/MWhel, but is currently £5.24/MWhel [73]. Furthermore, the project was to be financed from debt and equity sources, and the assumed terms of finance for the company from consultation with potential financiers. The term for equity return was assumed to be over the operational duration of the project, equity remuneration paid from the free cash flow, and the tax rate is correct for the 2010 financial year.

4.1 *Case study results ('as was' basis)*

Given the actual and projected data held by Energy Company, it is possible to model the techno-economic viability with a projected project cash flow, as shown in Table 8.

Table 8 – Expected demand cash flow

		Year					
Variable	**Unit**	**1**	**2**	**3**	**… 10**	**… 19**	**20**
Depreciation					…	…	
Beginning of year	£000s	4,000	3,600	3,200	… 400	… -	-
Depreciated	£000s	400	400	400	… 400	… -	-
End of year	£000s	3,600	3,200	2,800	… 0	… -	-
Debt					…	…	
Begin year debt	£000s	2,880.00	2,661.50	2,429.89	… 369.15	… -	-
Debt amortisation	£000s	391.30	391.30	391.30	… 391.30	… -	-
Interest	£000s	172.80	159.69	145.79	… 22.15	… -	-
Principal	£000s	218.50	231.61	245.51	… 369.15	… -	-
End year debt amount	£000s	2,661.50	2,429.89	2,184.38	… 0	… -	-
Production					…	…	
Electricity	MWhel	11,826	11,826	11,826	… 11,826	… 11,826	11,826
Utilised heat	MWhth	1,700	1,700	1,700	… 1,700	… 1,700	1,700
Income					…	…	
Energy sales and incentive revenue	£000s	1,497.255	1,497.255	1,497.255	… 1,497.255	… 1,497.255	1,497.255
Costs					…	…	
Fuel	£000s	-804.918	-804.918	-804.918	… -804.918	… -804.918	-804.918
O&M	£000s	-505	-505	-505	… -505	… -505	-505
EBITDA	**£000s**	**187.337**	**187.337**	**187.337**	**187.337**	**187.337**	**187.337**
Depreciation	£000s	-400	-400	-400	… -400	… -	-
EBIT	£000s	-212.663	-212.663	-212.663	… -212.663	… 187.337	187.337
Interest	£000s	-172.8	-159.69	-145.793	… -22.149	… -	-
EBT	£000s	-385.463	-372.353	-358.456	… -234.812	… 187.337	187.337
Income tax	£000s	0	0	0	… 0	… 52.454	52.454
After tax	£000s	-385.463	-372.353	-358.456	… -234.812	… 134.883	134.883
Return depreciation	£000s	400	400	400	… 400	… -	-
Deduct principal	£000s	-218.5	-231.61	-245.506	… -369.151	… -	-
Free cash flow	**£000s**	**-203.963**	**-203.963**	**-203.963**	**… -203.963**	**… 134.883**	**134.883**
ROE	**%**	**-**			**…**	**…**	
EBITDA NPV[1]	**£000s**	**-3559.242**					
Coverage Ratios					…	…	
Debt Service Cover	£000s	187.337	187.337	187.337	… 187.337	… -	-
DSCR, MAX:		**0.479**	**0.479**	**0.479**	**… 0.479**	… -	-

[1] EBITDA NPV (net present value) discounted at 14% [74].

Under this scenario, the project fails to meet the financial covenants with a DSCR less than required to service the loan and the targeted 1.35. It also fails to produce a positive return to the equity investors. Similarly, Table 9 shows a condensed cash flow for the site if they had been able to achieve the estimated potential for the site with increased heat and electricity utilisation (Table 5).

Table 9 – Potential demand cash flow (condensed)

		Year					
Variable	**Unit**	**1**	**2**	**3**	**… 10**	**… 19**	**20**
Production					…	…	
Electricity	MWhel	11,826	11,826	11,826	… 11,826	… 11,826	11,826
Utilised heat	MWhth	5,817	5,817	5,817	… 5,817	… 5,817	5,817
Income					…	…	
Energy sales and incentive revenue	£000s	1,810.372	1,810.372	1,810.372	… 1,810.372	… 1,810.372	1,810.372
EBITDA	**£000s**	**500.453**	**500.453**	**500.453**	**500.453**	**500.453**	**500.453**
Depreciation	£000s	-400	-400	-400	… -400	… 0	0
EBIT	£000s	100.453	100.453	100.453	… 100.453	… 500.453	500.453
Interest	£000s	-172.8	-159.69	-145.793	… -22.149	… 0	0
EBT	£000s	-72.347	-59.237	-45.34	… 78.304	… 500.453	500.453
Income tax	£000s	0	0	0	… 21.925	… 140.127	140.127
After tax	£000s	-72.347	-59.237	-45.34	… 56.379	… 360.326	360.326
Return depreciation	£000s	400	400	400	… 400	… 0	0
Deduct principal	£000s	-218.5	-231.61	-245.506	… -369.151	… 0	0
Free cash flow	**£000s**	**109.153**	**109.153**	**109.153**	**… 87.228**	**… 360.326**	**360.326**
ROE	**%**	**7.50%**			**…**	**…**	
EBITDA NPV[1]	**£000s**	**-1485.433**					
Coverage Ratios					…	…	
Debt Service Cover	£000s	500.453	500.453	500.453	… 500.453	… -	-
DSCR, MAX:		**1.279**	**1.279**	**1.279**	**… 1.279**	**… -**	**-**

[1] EBITDA NPV discounted at 14% [74].

The site, if able to reach the potential estimated levels of occupancy and utility demand, could be economically viable with a rate or return less than the required 15% target but suitable for some investor types, such as community share schemes. The project at this level of demand nearly reaches the DSCR target with 1.279. It also gives a significantly increased expected, yet still negative, EBITDA NPV (net present value) of -£1.485m.

This can also be shown by applying the levelised energy cost equation (Eq. 1) and algorithm depicted in Figure 1 to meet the minimum financial covenant requirements. The minimum LEC for the expected scenario is £86.60 MWhel and £70.36 for the increased demand in the potential scenario. As the minimum electricity unit value, in this calculation, also includes the benefit of revenue generated from the heat sales onsite; the potential heat demand scenario is significantly lower. However, with the current PPA agreement or wholesale electricity price at £40 MWhel, the project was not financially viable under the assumptions and terms of finance. Utilising the LEC method (Figure 1), it is possible to conduct a sensitivity analysis on each of the key project variables, as shown in Figure 3.

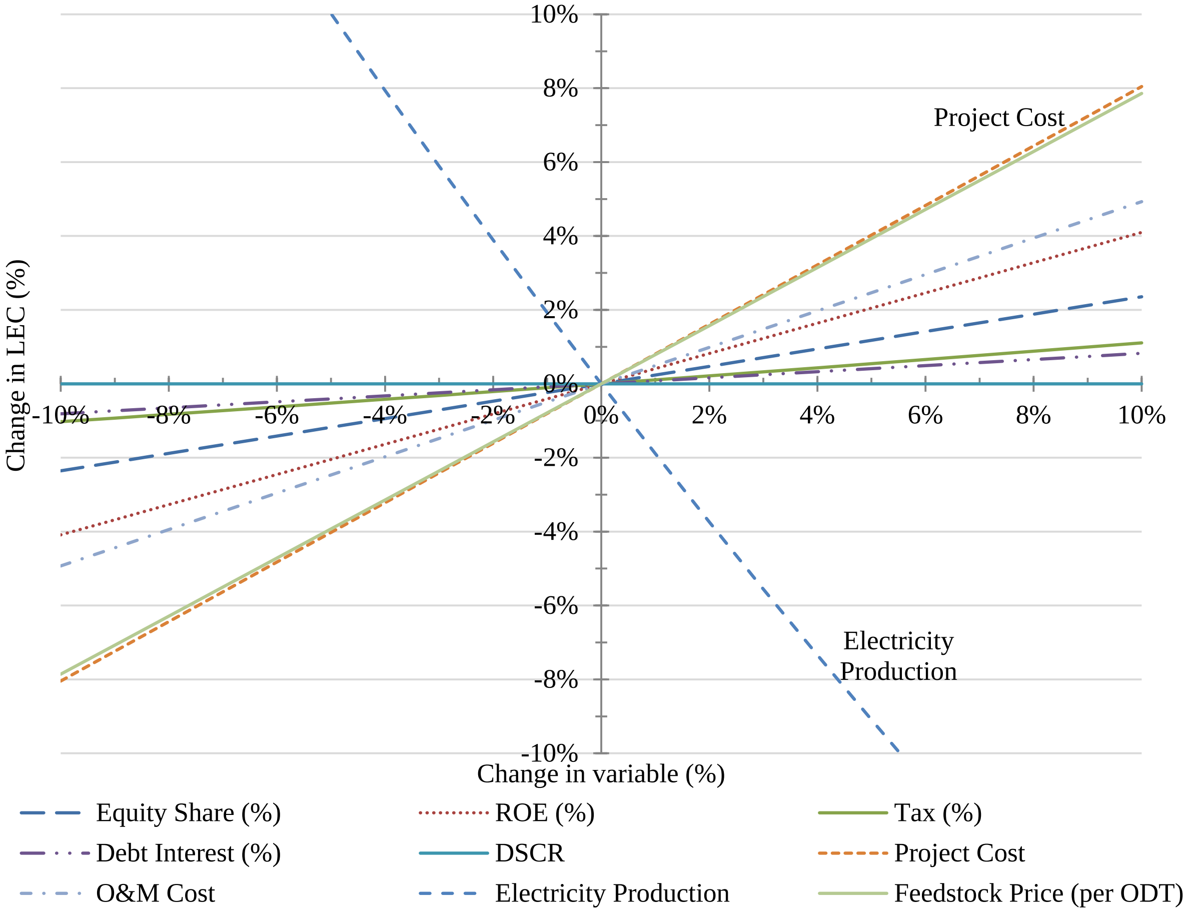


Figure 3 – Key variable sensitivity analysis

Electricity production appears to be the most sensitive project variable as a 1% change results in approximately a 2% change in the LEC. However, there is some distortion in the figure as the change in the levelised cost is expounded by the increased or reduced number of units (MWhel) to levelise. Second and third to electricity production movements are changes in the project cost or the feedstock price (per ODT). The feedstock operating expense as shown in Table 8 and Table 9 are the largest operating expense for this project, greater than the total O&M cost combined.

In conclusion, the case study project 'as was', in the actual and potential demand scenarios and under the given finance terms was not viable. The same LEC method is applied throughout Section 4.3 to conduct the analysis of the case and to support in suggesting improvements to the case study viability.

4.2 *Improving project resilience*

Section 4.2 exemplified some of the project issues under its proposed design. This section gives a more analysis of some of the wider issues with the project and suggests possible ways in which the project could have been improved to be more resilient and potentially be more investment ready. Furthermore, the sensitivity analysis highlighted the most sensitive project variables, these will be utilised as the basis for improving the resilience of the project.

4.2.1 *Capital structure*

For the case study, it was estimated that the project financed capital structure would be 50%-60% debt geared with the remaining capital being generated from equity sources. During the financial closing phase, the debt provider produces a term sheet for the sponsor that stipulates the terms of the loan. As debt is less costly than equity a sponsor will try to maximise the proportion of debt. However, at higher levels of debt the DSCR can significantly increase the levelised unit cost. Given the terms of finance or estimated in the early stages from market analysis, it is possible to calculate the effect of the capital structure on the minimum LEC, as represented in Figure 4.

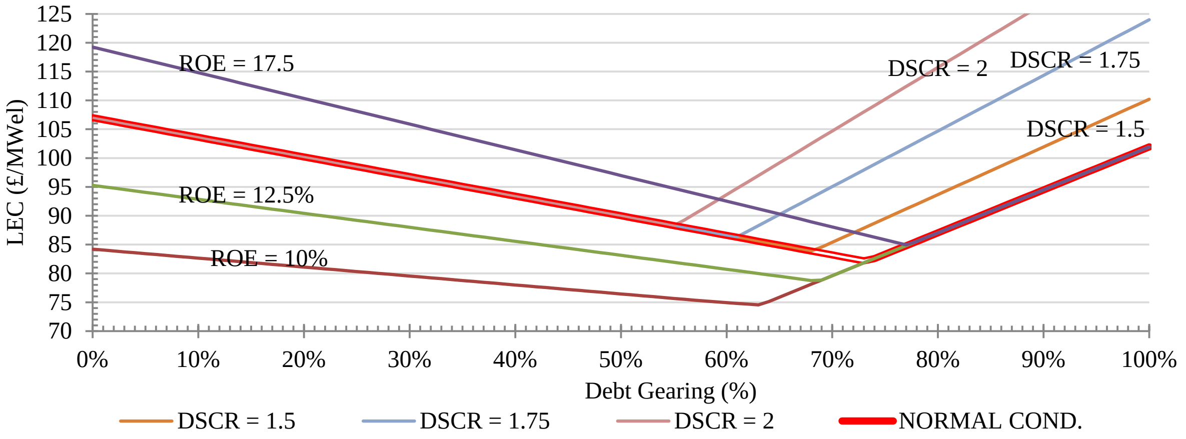


Figure 4 – Project finance capital structure and minimum LEC

At the offered maximum level of project debt gearing (60%) for the terms of finance offered, the minimum levelised cost for the project to break-even was £86.60 in the expected case and £70.36 in the potential demand case. As illustrated in the figure, increases in the DSCR increase the cost of projects with high levels of debt as it is necessary to increase the minimum LEC to reach the required levels of cover. Similarly, any reduction or increase in the require rate of return for investors has a significant effect at higher equity gearing levels. As the terms of finance change so does the optimal configuration of debt to equity for a project. In the normal condition (normal cond.) case illustrated in the figure, for a 20 year project life the optimal level of gearing is approximately 73% debt which would have reduced the LEC in the expected and potential cases to £82.18 and £65.94 respectively, but it was not possible to achieve this to the detriment of the project.

It later became evident that the debt and equity proportions of the finance did not constitute the entire capital required to fund the project. Before the project and ultimately company failed, the sponsors were considering utilising subordinate debt (mezzanine finance), as covered in Section 3.1. Although the cost of mezzanine finance has not been included in the calculation, it is stated by Fabozzi and de Nahlik [38] that it may be considered as equity for calculating the debt to equity ratio. As the subordinate debt is of a higher rate of return it would not improve the cost of capital to be more favourable than without it.

4.2.2 *Contract length and bankability*

As covered in Section 3.1, it is often necessary to have contracts or at least 'heads of terms' for feedstock supply and heat and power revenues in place to secure finance. For the case study, this issue created the most significant difficulties for the onsite sale of heat. As the company was not able to present a long term heat supply contract (as also identified by [56]) and could not guarantee the demand of the DHN supplied heat to the occupied residential and light industrial premises. It was not considered by the lenders they approached as a secure revenue stream. By removing the additional revenue of onsite heat sales from the LEC, there was an increase in the unit cost of c. £8 per MWhel. This significantly disadvantaged the project and at higher levels of onsite heat utilisation the benefit of the additional heat credit could ultimately have decided if the project was viable or not. This can be also shown in the project from the PPA output.

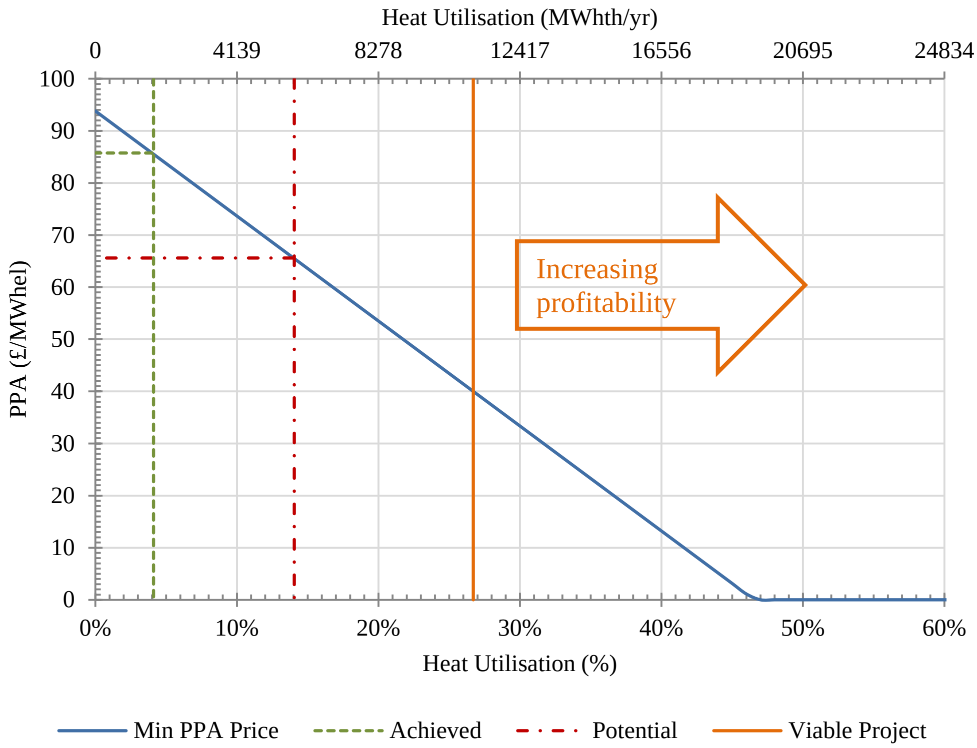


Figure 5 – Minimum power purchase agreement rate to break-even under the ROC with ROC uplift

The primary and secondary horizontal axes in the figure show the heat utilisation off-take as a percentage of total production annually and as MWhth respectively. At the achieved level of heat off-take for the site c. 1700 MWhth (4%) per year, the levelised cost was £85.74. If the site could have reached its forecasted heat off-take potential 5817 MWhth (14%) and remained competitive with current (2011) gas prices, the levelised cost would have fallen by approximately £20 per MWhel to £65.59. Additional heat sale and associated incentive revenue would continue to improve the levelised cost economics of the project with the required minimum PPA being reached at 26.7% heat off-take. Any heat off-take beyond this point would increase the profitability of the site to the point (47%) that if would theoretically be possible for the project export the power at no cost to the licensed supplier and remain viable on heat sales and associated electricity and heat incentives alone.

4.2.3 *Feedstock type and price uncertainty*

The largest operating expenditure for biomass plants, not using a waste feedstock, is the feedstock cost. The case study project was highly susceptible to feedstock price volatility and uncertainty over supply. As shown in the sensitivity analysis (Figure 3), a change of 1% in the feedstock cost (ODT) leads to a 0.8% change in the LEC. If the project could have secured an alternative feedstock at a lower cost, the viability and in turn attractiveness to investors could have been increased. It is possible to change the feedstock type and properties within the analysis to assess the viability of the project with different feedstocks. The energy content and price of some alternative feedstocks are given in Table 10.

Table 10 – Feedstock energy content and current (2010) prices and project viability

Feedstock	Energy density by mass(oven dry)		Source	Price estimations £/GJ (2010)			Modelled[9]	Results[10]	
	GJ/t	MWh/t		Low	Mid	High	£/ODT	LEC (£/MWhel)	NPV[11] (£000s)
Wood chips[1]	19	5.282	E4tech[5]	1.5	2.6	3.4	49.4	79.65	-2,764.68
Waste wood[2]	18.8	5.22	AEA[6]	-2	1	3	18.8	42.07	590.64
Straw[1]	18	5	AEA[7]	-	2.5	4.5	45	77.35	-2,559.01
Chicken litter[3]	15	4.167	AEA[8]	-	0.5	-	7.5	30.3	1,641.80
MSW[4]	9	2.5	AEA[4]	-12	-8	-4	-36	0	11,093.33

[1] Taken from [75] ; [2] Taken from [76] ID#1989 ; [3] Taken from [76] ID#3196 ; [4] Taken from [77] and [WRAP, 2010 cited in 77]; [5] Domestic price estimations (30,50,65 £/t) taken from [57] ; [6] Dependent on the grade/level of contamination ; [7] Mid-price is for unprocessed and high is for pelletised [77] ; [8] Taken from [77] ; [9] The costs modelled are taken from the mid-price; [10] 20 year operational term retaining the assumptions given in Section 4; [11] EBITDA NPV discounted at 14% [74].

The energy content and price estimations modelled by the company (4.8 MWh/t and £50t) slightly differed from the secondary data for wood chip (5.282 MWh/t and £49.4t), which had a higher energy content and lower cost. For a fairer comparison with the other feedstock data the secondary source estimation for wood chip was chosen over that modelled by the company. This slightly improved the economic viability of the wood chip case as the feedstock characteristics had improved. Each feedstock with its central price and energy content was entered into the economic model in turn to record the effect on the LEC and NPV.

It is likely that in the case of the MSW (municipal solid waste) and contaminated wood waste that there would need to be some increased additional flue gas cleaning equipment or waste disposal (fly ash) costs and these were not been accounted for. It was also assumed that that the level of contamination in the waste wood was minimal and it therefore still qualified for the ROC with sufficiently high biomass content by energy. In the case of MSW, it is possible to gain up to 1 ROC uplift for MSW with CHP for the biomass proportion of the qualifying heat output [78] and under the RHI (assessed by Ofgem) [55] but this was excluded from the model.

From the analysis it was clear that the waste feedstocks result in the lowest LEC. In some instances, the MSW plant would be viable without needing to charge for the electricity produced (as shown with £0 LEC). This levelised unit cost would likely increase if additional operational and waste incineration compliance costs were added to handle the waste, but it would still be a very viable project. Evidence of small-scale MSW plants in the UK such as NewLincs 3 MWel EfW CHP plant [79] supports the analysis of the benefits of community-scale schemes [80]. The feedstock with the second lowest LEC at £30.3 MWhel is chicken litter. This feedstock is eligible for ROCs but does not acquire a gate fee. The low cost and relative abundance of chicken litter in the UK [4] has also led to several plants being developed and operated by EPR [81]. The worst performing feedstock was the wood chip with a level or return very similar to that shown in Section 4.2.

4.2.4 *Plant oversizing*

The proposed plant size changed in the early stages of development from sub 1 MWel to 1.5 MWel net capacity. A larger plant size of 1.5 MWel was finally pursued by Energy Company as they believed that it was more profitable to oversize the plant than match the heat demand. This has also been concluded in earlier research by Wood and Rowley [13]. Furthermore, the company believed that they could also cover additional, non-project related, land lease expenses from the additional revenue generated with a larger plant.

To test Energy Company's hypothesis that oversizing is more profitable or viable than matching the heat load for this type of investment. For comparison three Turboden organic rankine cycle (ORC) plants were selected: TD6, TD7 and TD10 at sizes 611, 702 and 968 kWel respectively (Table 11). The performance of these systems were analysed utilising Turboden's data alongside the proposed 1.5 MWel system. As it was not possible to gather the actual cost data for these systems, it was assumed that the system costs are in line with DECC's biomass combustion CHP cost model [6], as shown in Figure 6. As ORC systems are generally more expensive, it is likely that the CAPEX and OPEX cost estimations are lower than actual.

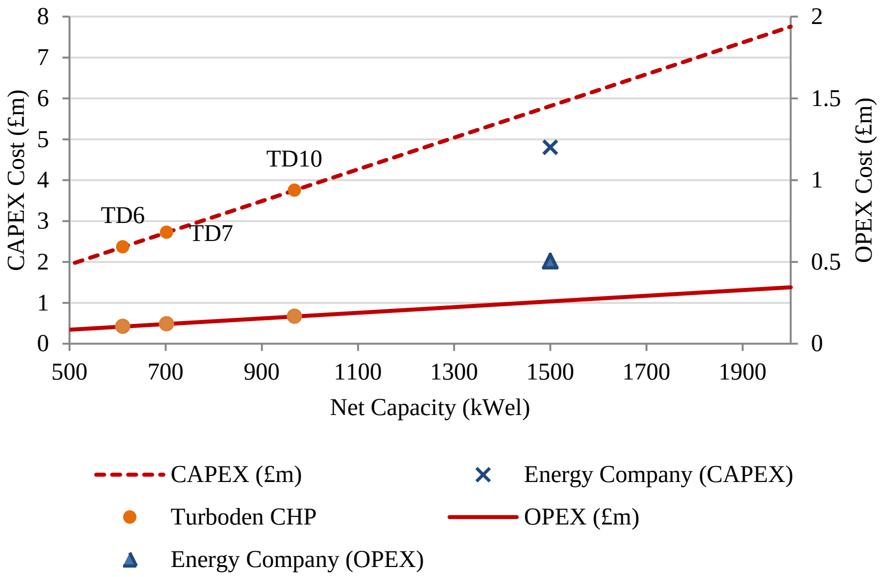


Figure 6 – Median modelled biomass <50MWel CHP and Energy Company's forecasted system costs

From the figure, it can be seen that Energy Company's CAPEX is £1m less than forecasted by DECC. Furthermore, the OPEX including the land lease (£250kpa) is approximately twice DECC's forecast of £259kpa at £505k. To have a more equal comparison between the different sized systems the CAPEX and OPEX of the Turboden systems and Energy Company's proposed system have been placed in line with DECC [6] assumed costs. Table 11 shows the comparative performance of the systems.

Table 11 – Turboden and Energy Company system comparison and performance

		Turboden systems[1]			
	Units	**TD 6 CHP**	**TD 7 CHP**	**TD 10 CHP**	**Energy Company**
Overall thermal power input	kWth	3340	3895	5140	
Output – hot water					
Hot water temperature (in/out)	°C	60/80	60/80	60/80	
Thermal power to hot water circuit	kWth	2664	3117	4081	
Performance					
Gross active electric power	kWel	643	739	1016	
Gross electric efficiency	%	19.3	19	19.8	
Captive power consumption (parasitic load)	kWel	32	37	48	
Net active electric power	kWel	611	702	968	
Net electric efficiency	%	18.3	18	18.8	
Model inputs					
Net capacity	MWel	0.611	0.702	0.968	1.5
Heat to power[2]		4.36	4.44	4.22	3.5
Thermal losses (boiler)[3]	%	15	15	15	15
Parasitic load[4]	%	5.24	5.27	4.96	12
Electrical efficiency	%	18.3	18	18.8	20
Availability	%	90	90	90	90
CAPEX[5]	£000s	2369.458	2722.356	3753.904	5817
OPEX[6]	£000s	105.398	121.095	166.98	258.75
Results (without site lease)					
LEC	£/MWhel	65.122	68.962	70.208	75.748
Results (with site lease £250kpa)					
LEC	£/MWhel	117.02	114.132	102.966	96.888

[1] Standard (not split) Turboden ORC units [82]; [2] Calculated as thermal power to hot water circuit / net active power efficiency ; [3] Boiler is independent from the ORC system so subject to the same inefficiencies ; [4] Calculated as captive power consumption / net active electric power ; [5] Total median assumed CAPEX [6]; [6] Total median assumed OPEX [6].

Without the site lease indirect cost for each of the systems, the smaller the system the lower the levelised unit cost with the TD6 CHP performing best with a LEC of £65.12. It can then be assumed that a smaller system than the TD6 could potentially have a viable LEC lower than the going PPA value of £40 MWhel. Smaller systems with a higher total CHP efficiency, in terms of utilising the potential thermal output, would receive a greater level of incentive under the ROC incentive support. Once the fixed site lease overhead is reintroduced as an annual operating expense, the larger systems performed better, with the proposed 1.5 MWel system performing best with the lowest LEC. The £96.89 LEC is similar to the projected cash flow and performance given in Table 8 and as equally unviable.

5. Conclusion

The research has highlighted the multitude of barriers to be overcome and the necessary stakeholders required to successfully develop small-scale bCHP plants within the UK. Several stakeholders are vital to the successful development of a biomass CHP scheme (as shown in Figure 2), with each stakeholder or the contract required presenting a unique set of challenges for either party. Importantly, the heat user and the heat off-take contract (Section 3.7) barriers are unique to CHP or heat only schemes, but likely more important to the former as there are increased capital costs and therefore a longer payback period. In project financed bioenergy schemes, the lender is the primary enforcer of contracts with the key stakeholders [35]. Lenders attempt to de-risk investments where possible [35, 36] and desire set of key characteristics in project sponsors and a thorough feasibility study, financial and risk management plans [38].

The problems faced by Energy Company were also representative of the wider industry, which may offer some explanation to the high number of renewable energy projects failing [5] and the very low rate of CHP capacity growth in 2011 [4]. Not addressing these barriers greatly inhibits biomass reaching approximately half of the new energy production needed to meet the UK's 15% primary energy generation target by 2020 [1]. The analysis showed that the project was not viable under the modelled assumptions and terms of finance. The 'as was' case confirmed this with an unachievable levelised unit cost and low EBITDA or negative free cash flow for the duration of the debt term. Modifications to the proposed scheme were shown to improve its viability. These were namely:

- the possible change of feedstock type to a less costly waste or residue;
- a reduction in the operating expenditure, especially a reduction in the land lease cost;
- an increase in the amount of heat utilisation on site or securing a financier that would consider heat sales as a bankable revenue stream.

Additionally, there was the issue of contracts and supplying a portfolio or wide range of small heat users not being considered as secure as a large heat user, such as an industrial plant, public leisure centre or social housing development. This may possibly explain a complete lack of community scale projects in the UK that have successfully circumvented this barrier. Moreover, this view also aligns with the barriers covered with the heat off-take contracts barrier section within Section 3.7. This analysis shows that there was some truth in the logic applied by Energy Company. Although, a smaller system without the fixed and additional overheads, yet with a higher level of efficiency than utilising more than 5% of the electricity and 4% of the heat onsite could have been successful.

The capital structuring section (4.2.1) theoretically shows the value of being able to manipulate the gearing ratio of the project. However, one needs to consider that in reality there is little opportunity to do this with the gearing being set by the debt provider and the rates and conditions of the loan being stipulated in the term sheet. The interest rates and conditions would also change with regard to changing levels of gearing as there is likely to be a change in the risk profile of the project.

Overwhelmingly, the biomass and more generally the renewable energy industry are primarily compensated for the production of electricity not renewable or low carbon heat production. This has an impact on the economics of the project and the desire to produce as much electricity as possible. Not to design the most efficient system that utilises all or at least a significant proportion of the heat produced.

The modelling given in the analysis also was likely to present a more positive or favourable level of project performance as there is the assumption that the CHP load can always be met wholly by the sized engine, which may not be the case for peak load periods. It also assumes that the entire site load is covered by the engine when it is operational, not allowing for the negative financial impact of plant down time. Within further research, the effects of improving the project's financial viability by remunerating the equity investor(s) with subordinated debt not from the free cash flow is to be modelled. This would impact the break-even LEC calculations by remunerating equity investors from a subordinated debt cash-flow and not delaying payment until the project begins to make a positive return from the free cash flow. This is more representative of how equity debt is structured in projects financed of this type.

As somewhat expected project exposure to the aforementioned barriers (Table 3) or to ones not captured within the existing literature or within the case study is often project specific and circumstantial. There were also some of the cited barriers that did not lead to the projects failure but delayed the development of the project such as the Government's proposed introduction of the RHI resulting in a development hiatus or reduced its attractiveness in the case of the cost of connect to the distribution grid. One barrier that contributed to Energy Company's project ultimately failing was directly aligned with those covered in the barriers section; the bankability of heat contracts to multiple small private tenants [14, 58, 59]. This barrier significantly contributed to the development being considered by project financiers as a not sufficiently attractive investment which led to the dissolution of the company. The techno-economic methods utilised can be beneficial to increasing the resilience of future projects of this kind. The techno-economic methods can also be more widely applied to other renewable energy or fossil fuel technologies, such as natural gas CHP.

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